NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Technical Rationale

Project 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues
Reliability Standard PRC-030-1 | June 2024

PRC-030-1 – Unexpected Inverter-Based Resource Event Mitigation

Rationale for Applicability Section

The functional entity responsible for identifying, analyzing, and mitigating unexpected Inverter Based Resources (IBR) performance is the Generator Owner (GO). The Generator Operator (GOP) is not included because of the accountability and coordination issues introduced by listing both GO and GOP as responsible functional entities. Further, this standard intentionally did not include requirements for the Balancing Authority (BA), Reliability Coordinator (RC), and Transmission Operator (TOP) because other standards (e.g., EOP-004) place requirements on these entities for system level events.

General rationale

Aligned with the Project 2023-02 Standards Authorization Request (SAR), the Requirements are structured to identify, analyze, and mitigate IBR performance issues. The SAR discusses how a series of NERC disturbance reports have "identified the undesired performance of bulk power system (BPS)-connected inverter-based resources (IBRs) during grid faults, and have elaborated on the systemic and significant BPS reliability risks that these pose". [1,2,3,4,5,6,7,8,9] In particular, IBR performance during events has included tripping or momentary cessation that is unexpected, unwarranted, and poses reliability challenges.

Requirement R1 defines how events are to be identified, along with exceptions that should not be identified. Requirement R2 requires analysis of identified events, with specific elements assessed as

[1] *Odessa Disturbance,* NERC. September 2021.https://www.nerc.com/pa/rrm/ea/Documents/Odessa_Disturbance_Report.pdf
[2] *2022 Odessa Disturbance,* NERC. Atlanta, GA: December 2022. https://www.nerc.com/comm/RSTC_Reliability_Guidelines/NERC_2022_Odessa_Disturbance_Report%20%281%29.pdf
[3] *900 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report*, NERC. Atlanta, GA: February 2018. https://www.nerc.com/pa/rrm/ea/October%209%202017%20Canyon%202%20Fire%20Disturbance%20Report/900%20MW%20Solar%20Photovoltaic%20Resource%20Interruption%20Disturbance%20Report.pdf
[4] *April and May 2018 Fault Induced Solar Photovoltaic Resource Interruption Disturbances Report*, NERC. Atlanta, GA: January 2019. https://www.nerc.com/pa/rrm/ea/April_May_2018_Fault_Induced_Solar_PV_Resource_Int/April_May_2018_Solar_PV_Disturbance_Report.pdf
[5] *Panhandle Wind Disturbance*, NERC. Atlanta, GA: August 2022. https://www.nerc.com/pa/rrm/ea/Documents/Panhandle_Wind_Disturbance_Report.pdf
[6] *Panhandle Wind Disturbance*, NERC. Atlanta, GA: August 2022. https://www.nerc.com/pa/rrm/ea/Documents/Panhandle_Wind_Disturbance_Report.pdf
[7] *1,200 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report*, NERC. June 2017. https://www.nerc.com/pa/rrm/ea/1200_MW_Fault_Induced_Solar_Photovoltaic_Resource_/1200_MW_Fault_Induced_Solar_Photovoltaic_Resource_Interruption_Final.pdf
[8] *San Fernando Disturbance*, NERC. November 2020. https://www.nerc.com/pa/rrm/ea/Documents/San_Fernando_Disturbance_Report.pdf
[9] https://www.iec.ch/conformity-assessment/what-conformity-assessment

described in subparts. Requirement R3 requires a Corrective Action Plan (CAP) or technical justification when corrective actions are needed. Finally, R4 requires mitigation of the performance risk through CAP implementation. The flow of these requirements is summarized in Figure 1.

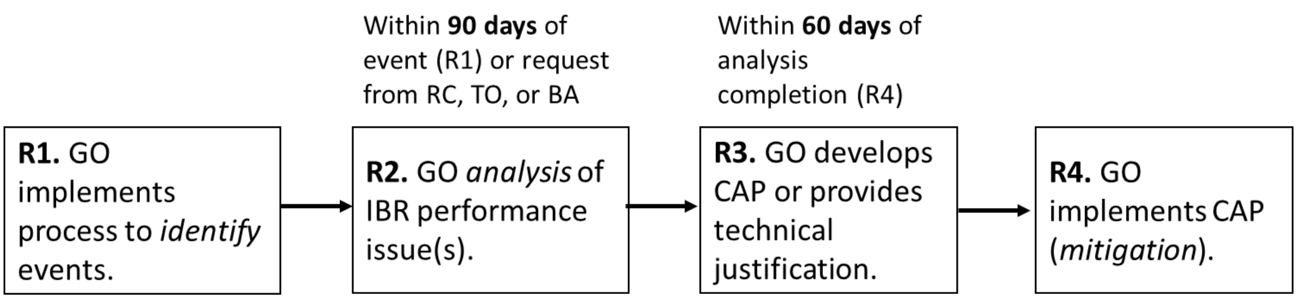

Figure 1.1: Relationship of Requirements in PRC-030-1

The Requirement R1 contains thresholds for identifying events with sudden changes in active power. Figure 1.2 depicts the threshold criteria and logic used in Requirement R1, along with additional details of process flow in Requirement R2.

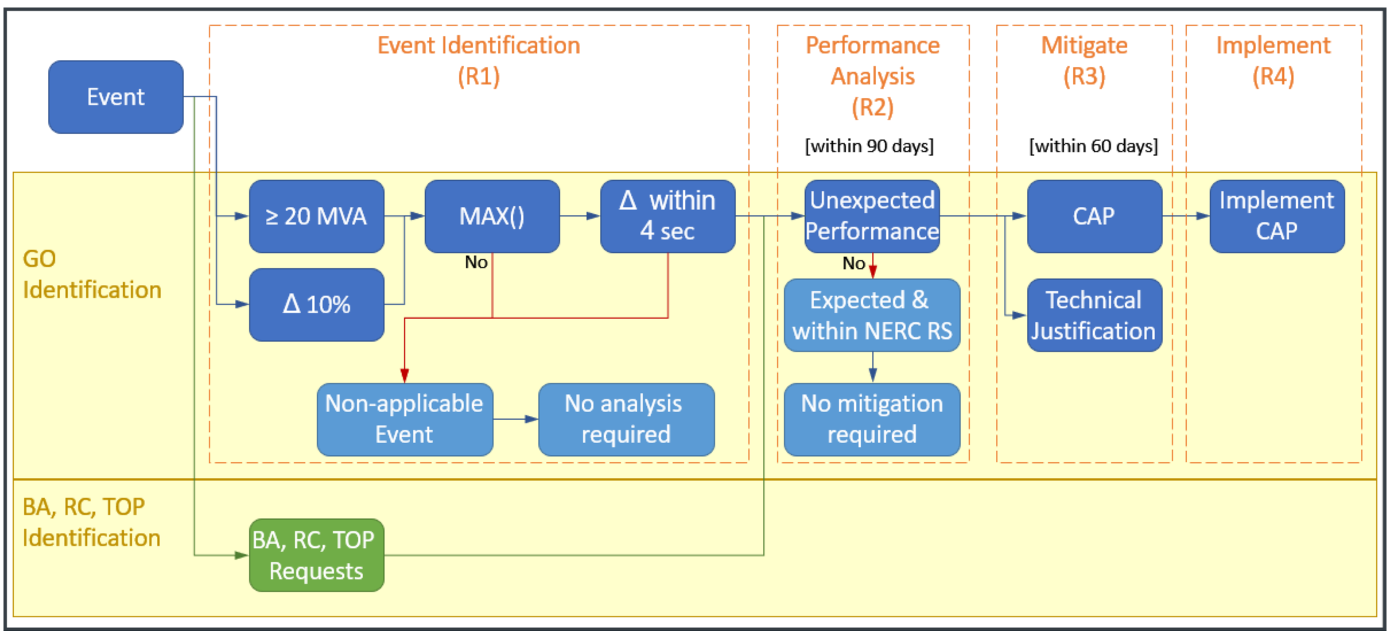

Figure 1.2: PRC-030-1 Flowchart

Rationale for Requirement R1

The intent of Requirement R1 is for the Generator Owner (GO) to implement a documented process to self-identify events that are sufficiently large to warrant an analysis of IBR performance for the identified event.

While the GO should consider both active and reactive power responses when an analysis is required, only active power is used as a threshold to trigger analysis. Active power was selected as the monitored parameter to make feasible implementation across IBR plant designs and backend software system (e.g., SCADA).

Nameplate rating was used as the basis of the change (power or amperes) because it is the common reference in NERC and other industry standards. The IBR continuous rating concept outlined in IEEE 2800-2022 definitions was considered and determined to be a departure from NERC standards approaches to date.

The 10% magnitude of event threshold was chosen to be large enough to screen out small active power changes but low enough to detect events that should be analyzed for reliability purposes. The percent change is mainly intended to address large units where 10% is a significant change, otherwise the 20 MW threshold sets a minimum threshold for event identification. For smaller capacity facilities, the use of only a percent change as the screening criteria would lead to identification of disturbances that are not likely to be significant for analysis.

The intention of the period no longer than four second was to define a sudden change in power, similar to the types of active power loss events described in NERC Disturbance Event reports. The intent is to exclude from review slow power changes expected with normal operations (e.g., variable output from weather, dispatch, planned outages, testing) or expected responses (e.g., loss of interconnection facilities), which were defined as bullet points to Requirement R1.

The various SCADA scan rates in use at ISOs/RTOs as well as NERC standard minimum required scan rates were considered in selecting four seconds. SCADA monitoring is a likely method for monitoring active power changes. Power changes that occur and recover within one scan are not expected to be detected by the Requirement R1 process implemented by GOs. The four seconds was not intended to define the scan period, but only to characterize the change as sudden when considering information on monitoring capabilities across the industry. It should be noted that selecting longer time periods could lead to a need for more sophisticated event screening or may otherwise lead to identification of more invalid events that occur on slower timescales.

The term “changes in active power” encompasses both sudden decreases (i.e., loss of output) and increases (i.e., additional consumption) that may be caused by IBR mis-operations that could affect system reliability. For instance, a battery energy storage system that mis-measures system frequency may unexpectedly enter a charging mode and suddenly increase active power draw.

Photovoltaic (PV) example 1 – qualifying:
PV facility with gross nameplate rating of 220 MW is operating with active output of 80 MW. During a transmission system fault event,[10] the plant exhibits a near instantaneous active power output drop to 50 MW.

[10] The transmission line fault is assumed not to be on the line connecting the IBR to the system, but rather is a fault remote from the IBR.

The change in apparent power in under four seconds is 30 MW, which exceeds 22 MW, the greater of 10% of the plant's gross nameplate (22 MW) or 20 MW. This IBR performance event is required to be captured by the GO's process implemented in Requirement R1.

PV example 2 – non-qualifying:
PV facility with gross nameplate rating of 80 MW is operating with active output of 60 MW. During a transmission line fault event,[1] the plant exhibits a near instantaneous active power output drop to 42 MW.

The change in apparent power in under four seconds is 18 MW, <u>not</u> exceeding 20 MW, the greater of 10% of the plant's gross nameplate rating (8 MW) or 20 MW. This IBR performance event is <u>not</u> required to be captured by the GO's Requirement R1 process.

Battery Energy Storage System (BESS) example 1 – qualifying:
BESS facility with gross nameplate power output rating of 80 MW is operating as a load drawing 50 MW. During a power plant controller ("PPC") malfunction event of the BESS facility, the PPC incorrectly estimates system frequency sending an incorrect frequency response signal causing the plant to exhibit a near instantaneous change in real power to 10 MW injection.

The change in apparent power in under four seconds is 60 MW, which exceeds 20 MW, the greater of 10% of the BESS gross nameplate (8 MW) or 20 MW.
This IBR performance event is required to be captured by the GO's R1 process.

BESS example 2 – non-qualifying:
BESS facility with gross nameplate power output rating of 80 MW is outputting 40 MW. The BESS facility is curtailed by the RC such that the plant exhibits a near instantaneous active power decrease to 15 MW.

The change in apparent power in under four seconds is 25 MW, exceeding 20 MW, the greater of 10% of the plant's gross nameplate rating (8 MW) or 20 MW. However, the change in apparent power is the result of the RC curtailment which is an exempt event per R1. This IBR performance event is <u>not</u> required to be captured by the GO's Requirement R1 process.

Rationale for Requirement R2

Requirement R2 requires analysis of events that meet Requirement R1 thresholds. Requirement R2 also provides an alternative path of event identification by the BA, RC, or TOP. It is anticipated that some events would only be detected by one entity, but the combination of both identification methods would better identify events potentially posing reliability challenges.

Requirement R2 allows 90 days to analyze expected versus actual IBR responses to place an emphasis on diligent resolution, while still allowing enough time to conduct an analysis and identify causes. Ninety days allows adequate time for Generator Owners (GO) to interact with manufacturers and examine capabilities of equipment. This time was chosen to be closer to the PRC-004 timeline of 120 days while recognizing important differences between the application of these standards. PRC-004-4(i) Technical Rationale states "The 120 calendar day period accounts for the sporadic volumes of Protection System operations, and provides the opportunity to identify any Misoperations which were initially missed".[11] The PRC-004 timeframe accounts for extreme weather events such as hurricanes that may affect a very large number of Protection Systems for a given responsible entity. The volume of IBR exposed to potential expected operation is anticipated to be lower when compared to Protection Systems and therefore a shorter timeframe is appropriate for PRC-030. The 90-day period starts from the event date for GO-identified performance issues resulting from Requirement R1 or upon request from the Balancing Authority (BA), Reliability Coordinator (RC), or Transmission Operator (TOP) regarding IBR responses identified during system events.

Requirement R2.1 has subparts to ensure the root cause is identified (R2.1.1); the facility Ride through and reactive power performance is documented (R2.1.2); the issue is assessed and determination whether corrective actions are needed (R2.1.3); and applicability to other similarly designed units is considered (R2.1.4). Collectively, the subparts define the minimum features required as part of an effective analysis. Requirement R2.2 closes the communication loop with BA, RC, and TOP entities, should these entities request analysis results.

Rationale for Requirement R3

Should Requirement R2 determine a need for corrective actions, Requirement R3 requires a CAP or technical justification be developed within 60 calendar days of completing the analysis in Requirement R2, as identified in Part 2.1.3. If R2 did not identify the need for corrective actions, then R3 does not need to be performed.

Resolving the causes of IBR performance issues benefits Buk Power System (BPS) reliability by preventing recurrence. The CAP is an established tool for resolving operational problems. The NERC *Glossary* defines a Corrective Action Plan as, "A list of actions and an associated timetable for implementation to remedy a specific problem." Since a CAP addresses specific problems, the determination of what went wrong needs to be completed before developing a CAP. When the IBR Performance issue cause(s) is identified in Requirement R2 or Requirement R3 requires Generator Owner(s) to develop a CAP or provide a technical justification that addresses why corrective actions will not be applied nor implemented.

This standard recognizes there may be multiple causes for IBR performance issues. In these circumstances, the CAP would include a remedy for the identified causes. The CAP may be revised if additional causes are found; therefore, the entity has the option to create a single or multiple CAP(s) to correct multiple causes of an IBR performance issues. The 60-calendar day period for developing a CAP or technical justification is established based on industry experience which includes operational coordination timeframes, time to consider alternative solutions, coordination of resources, and development of a schedule.

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[11] Standard PRC-004-4(i) – Protection System Misoperation Identification and Correction. Available at: https://www.nerc.com/pa/Stand/Reliability%20Standards/PRC-004-4(i).pdf

The development of a CAP is intended to document the specific corrective actions needed to be taken to prevent IBR performance issues from reoccurring, the timetable for executing such actions, and an evaluation of the CAP's applicability to the GO's other IBR including those at other locations. The evaluation of these other IBR with similar designs aims to reduce the risk and the likelihood of similar IBR performance issues in other IBRs. The GO is responsible for determining the extent of its evaluation concerning other IBRs and locations. The evaluation may result in the GO including actions to address IBR at other locations or to provide a technical justification that addresses why corrective actions will not be applied nor implemented.

Acceptable technical justification for not performing corrective actions is expected to primarily have two characteristics:
1) interconnection requirements on IBR performance extending beyond those in place at the time of interconnection; and
2) it would require material modifications/qualified change.

Technical justifications for not performing corrective actions do not relieve the GO from compliance to other standards (i.e., PRC-029-1 Ride-Through) to the extent that other standards are applicable.

Rationale for Requirement R4

Requirement R4 requires that each entity implement the CAP developed in Requirement R3, as applicable, to mitigate deficiencies identified in Requirement R2. In the NERC *Glossary*, a CAP is: "A list of actions and an associated timetable for implementation to remedy a specific problem."

A CAP can be modified if necessary to account for adjustments to the actions or scheduled timetable of activities. If the CAP is changed, the entity must notify the applicable RC(s), TOP(s), or BA(s). The entity must also notify applicable RC(s), TOP(s) or BA(s) when the CAP has been completed. The implementation of a properly developed CAP ensures that causes of unexpected changes in IBR power output are mitigated in a timely manner.

An IBR deficiency may require the RC, TOP, or BA to impose operating restrictions so the system can operate in a reliable way until the CAP is completed. The possibility of such operating restrictions should incentivize the entity to complete the CAP as quickly as possible.